# NWX-DEPT OF INTERIOR-GEO-1 (US)

**Moderator: Bev Winston**
**December 3, 2015**
**1:00 pm CT**

Woman: Why the changes to the current rules? We've got plenty of people in the room to help you out with that. We're going to take a break. It's going to - you know, if you need a break, ways to me. Otherwise I'll decide when it is. They'll be about halfway through the afternoon.

And it's only going to be about ten minutes. There is - this is going to be repeated about ten times this afternoon, and that is that the cut off for comments on these particular rules is December 14th.

It's been extended from - from my understanding, it's been extended a couple of times before but this is a pretty firm date. So, if you don't want to speak today, you know, if you have public speaking fear, just send your comments in.

We're going to give you addresses in emails and waste to do it and people to call. So there are several different ways to do this. Does anybody have any questions before we begin? And if it's a technical question, you don't need me.

Anybody have any questions before we start? Okay, are we - is (Sheila) doing this, (Karen), or are you?

Karen Morrison: Okay, hello, everyone and thank you for coming. Is this - am I talking - holding it close enough? My name is Karen Morrison on the deputy assistant director for energy, minerals and reality management for the Bureau of Land Management in our Washington office.

And so I work in an office where we work on policies such as this one. So I really thank you all for coming. I'd like to introduce the BLM people who are here and then we'll get started here.

To - let's see, some of the people from our Washington office are here. (Steve Wells), who's the division chief for our fluid minerals group, our oil and gas group in the Washington office.

(Bill Infuge), who's a senior advisor to our director in our Washington office. And our experts here, were going to talk to you about this rule, (Mike Wade), who works in our inspection program, (Mike Maclaren), who's a petroleum engineer, and (Richard Estabrook) who's a petroleum engineer for our office.

So thank you all for being here. And as you know, we want - we have put out these draft regulations on oil and gas measurements and we want your comments. They want your comments on the regulatory text.

As they go through the presentation, they're going to point out some areas, some very specific things, that we would like comments on from you all. But we want comments, you know, on anything, really, even - you know, the specific things and anything else.

There is a - the preamble, the explanatory section of these regs, we'd like your comments on. We have environmental analysis. There's also a document called a Regulatory Impact Analysis. It goes to the costs that we think these regulations will cost to implement them, both the cost for the government to implement in the cost for producers to implement.

And so that's on the Web site and described in the Federal Register notice. So we would like your comments on that, if you have ideas on how we calculated those costs or if we need additional information.

And as a facilitator said, December 14th is our comments due. The Federal Register notices and the press release all have the places where you can send your comments in. The Federal Register notices also have these guy's names and phone numbers if you want to contact them for information.

So, you know, there're lots of ways you can get your information to us. I did just want to introduce why we're here. Probably you all know this but these regulations were last written or were written in 1989, I think it was.

As they're going to point out, there are some parts of them that are pretty out of date. The technology has changed. The referencing things. The standards are out of date.

So that's one reason we're doing this. We have also had a number of groups to audits of these regulations and our program which (Rich) will talk about a little bit.

But they have also said, "Look, BLM, you need to revise these regulations." And we really want to ensure that we're adequately accounted for the volumes of oil and gas and that goes to the revenue. It goes to the royalties we collect.

And so the government and the tribes get the proper amount of royalty but it's also - you know, it could go both ways, so we don't want to producers paying more than they owe, either.

So it's for everyone's benefit to measure this accurately. Our court reporter is just taking on everything so that we can make sure we capture everything you all say and we'll look at that as we look at the other comments, everything she gives us.

So - and then after the 14th when we get these comments, we'll look at everything. We really want to look at these comments, as I said, and try to figure out if we need to make any changes to our proposed regs and, you know, if so what they will be.

And we're just going to move forward as quickly as we can to work through that. But I don't have an exact date. It will depend on how many comments we get. So I think that's about all of the introductions. And shall we - you want to start, (Rich)?

(Richard Estabrook): How about this? All right. The way we have the presentation today organized is that we're going to get all the presentations out of the way right up front and then the rest of the afternoon is for you guys to comment and ask questions for clarity.

So I hope that works out okay. For the one in Durango, we ended up taking a break after the end of our presentation but we'll just kind of see how it goes. So with that, let me just kind of jump into this.

Why are these regulations important? And I think this is going to be information that you all know very well but I just thought I'd throw up some equations here. Got to start with equations.

Royalty on oil is calculated by taking the royalty rate on the lease, which is usually a fixed number set in the lease terms, 12-1/2%, is very common for federal leases, multiplying that by the volume of the oil removed from a lease in a given month, and then multiplying that by the dollar value of the oil.

You multiply those three things together and you get the royalty that's do for that lease that month. One of the things that goes into the calculation of value is the API gravity or the oil quality.

It's not a direct multiplier in the royalty calculation but it does affect the value. Now the royalty rate is set in the lease terms and it has nothing to do with (Entra orders) Form 5 or 3, 4 and 5, and I'm not going to be talking about that aspect of the royalty formula today.

The dollar value of the oil is established by the Office of Natural Resource's revenue. It's not our agency that does that. It's a different agency within the Department of Interior that establishes the dollar value of the oil.

(Entra Order) 4, and to some degree (Entra) Order 3, has a direct bearing on the accuracy of measurement of oil volume and the proper reporting of oil volume.

So the proposed changes to (Entra) Orders 4 and 3 will have a direct impact on the accuracy in reporting of the volume of oil on which a royalty is due. (Entra) Order 4 also impacts the determination the reporting of oil quality, the API gravity.

For gas, the equation is similar. Royalty is the royalty rate on the lease times the volume of gas removed from that lease in a given month times the heating value of the gas times the dollar value.

Again, royalty rate is established in the lease terms. That has nothing to do with the (entra) orders we're discussing today. It's normally 12-1/2%. In the leases, the royalty is different and can vary, I believe. Okay.

The dollar value of the gas, just like with oil, is not established by the BLM. That's established or verified by the Office of Natural Resources revenue. (Entra) Order 5 and BLM's responsibility is about ensuring accurate measurement and proper reporting of volume on which royalty is due and ensuring the accurate determination and reporting of heating value which also affects royalty.

One thing I want to point out in this equation is that both royalty -- or excuse me -- and heating value have an equal effect on royalty. So if volume was reported or measured, let's say, 10% in error, it's going to cause a direct 10% error in the royalty due on that lease.

Likewise, if heating value is measured or reported 10% in error that will also result in that same 10% error in royalty pay. So volume and heating value have equal bearing on the royalty that's ultimately paid for a lease.

Why are we revising these regulations? Some of this has already been mentioned. Before I get into the why, I just want to go over specifically what our proposal is. Currently we have (Entra) Orders 3, 4 and 5.

Now, (Entra) orders, as far as I know, are the only - they're very unusual and I don't think any other program and the government has a similar thing as (Entra) orders.

(Entra) orders are regulations, the full force and effect of regulations, but they're not published anywhere. You can go to a regulation book, a CFR book, and find them. They are not there.

They're on our Web site. People have copies floating around but they were - it's uncodified. So what we're proposing to do - now, one of the things we're proposing to do, is to take these uncodified regulations, the (Entra) orders, and developing new subpart under 43 CFR - CFR is Code of Federal Regulations.

Part 3170, contain everything that has to do with production and measurement. And that would include definitions, record-keeping statements about bypass and tampering, variances appeals and enforcement.

These are common to anything that relates to production and measurements so they would be pulled out and put into one - in one place under this Part 3170. Also, Part 3170 contain a new subpart, 3173, it would replace (Entra) Order 3 and it would deal with (some) security, FMPs, which is a Facility Measurement Point, co-mingling and off lease measurement. And (Mike Wade) will be getting into the specifics of that here in a little bit.

Part 3170 would also contain a new Subpart 3174. This would replace (Entra) Order 4 and it would deal specifically with the specifics of oil measurement. And (Mike Maclaren) will be getting into kind of the nuts and bolts of the - of that proposal.

We would also have Subpart 3175. This would replace (Entra) Order 5 and it would also replace the statewide notices to lessees for electronic flow computers. As you may or may not be aware, every jurisdictional states within the BLM has an NTL that covers electronic flow computers. And those will be replaced by this new Subpart 3175 and all of these things deal with gas measurement.

So why revise these orders? Well, for one thing, the bullet says last revised in 1989. That's actually not correct. The (orders) were promulgated or developed in 1989 for the first time in they've never been revised.

So they're 26 years old. The current orders do not address new technology or incorporate the latest industry standards and practices. For example, Coriolis meters which are now commonly used for oil measurements, are not addressed in (Entra) Order 4. Again, (Entra) Order 4 was developed in 1989.

There are gaps in existing orders they need to be addressed. For example, (Entra) Order 5, the gas measurement one, has one, and only one requirement, for heating value determination, and that is that BTU contents must be determined once per year. And that's it.

There're 24 or 25 regulations or provisions for volume side, and only one for the heating value side. As my equations showed, both volume and heating value are equally important in the calculation of royalties.

So there's a huge gap in our heating value requirements. We have no requirements for how you sample, where you sample, how you analyze or how you report heating values.

And we also need to respond to various reports and audits that Karen mentioned. GAO, the Government Accountability Office, did a - they oversee us to make sure we're doing our job.

And they wrote a report in 2010 that numerous deficiencies in our regulation of oil and gas production and measurement. And one of the recommendations was to update our (Entra) orders.

The Office of Inspector General is another agency that oversees how we do our job and they've written numerous reports showing deficiencies in our ability to regulate measurement, ensure accurate measurement and proper reporting.

Our PC, the top bullet there, is the royalty policy committee, is a chartered advisory committee under the old minerals management service. And in 2007, they did an exhaustive study on the Department of Interior's oil and gas management program that included onshore, offshore in the royalty selection people.

And they found, or they had 110 recommendations of things that BLM, as a department, has to do to fulfill our responsibility, are fiduciary responsibility, to ensure accurate measurement and proper reporting.

Of those 110 recommendations, 12 of them dealt directly with measurement of volume and quality and a lot of that was needing to update your regulations on measurement.

So the bottom line is why revise these orders? Because we want to improve measurement accuracy, reporting and accountability. So I'm now going to go through a couple of changes that would be common to all three proposed subparts, 3173, 3174, 3175.

In the onshore orders, if you're familiar with onshores - how many of you have reviewed the existing onshore orders and are familiar with them? Okay, good. For those of you familiar with the existing onshore orders, each onshore order has a number of provisions.

And after each provision, there is a statement as to whether that's a major or minor violation, what is the corrective action and what is the timeframe for that corrective action?

Now both BLM and industry commonly misinterpret that enforcement major, minor, corrective action timeframe as being absolutely mandatory. And that was never its intent because the determination of a major violation, we must to find a violation as substantial, immediate and adverse.

Now, major violation for a tank seal, for example, would be appropriate for a big tank. But if you have a little tank out there that gets filled up every three months and there are two feet of oil and it, maybe that seal violation doesn't meet the criteria for things substantial, and so it could be a minor violation.

So what we're proposing to do is remove those enforcement actions from the regulation itself and put them into a handbook. In the handbook, we can go into a great amount of detail provided what circumstances are required for a violation in order to elevate into a level of major.

We're hoping that will eliminate a lot of the existing confusion about what constitutes major and minor and what corrective actions and time frames have to be.

The existing orders have one immediate assessment. Is where an inspector can go out and identify a violation and immediately assess the dollar amount, a fine, basically.

The proposed regulations would implement numerous immediate assessments that would be added to each subpart for something called liquidated damages. The attorneys in the room can explain what liquidated damage is. I don't really understand it but that was the idea.

Each immediate assessment, the proposed dollar value for each immediate assessment is $1000 across-the-board for instance. The current orders - if you want to do something different, you want to do - use a different meter or a different procedure, you have to go to the local field office and ask for a variance.

The problem with this, and I've heard this from industry actually, is that there's a tremendous lack of consistency in how that variance is processed at the field office level.

I can think of an example and Wyoming where there's a new type of gas meter that was requested. One office basically said, "Fine, go ahead and use the meter." Another office in the same state reviewed it inside, "You can use it but with these conditions."

And the third office at the same request for the same meter and said, "There's no way are you're using it in our field office." So what we're proposing is that we would establish a new national level production measurement team to provide meter device approval at a national level.

We believe, for one thing, this would remove the inconsistencies of field office to field office variance reviews and conditions of approval. How we envision this working is that a new technology would be that - the data for this new technology, it could be a piece of equipment, it could be a procedure - would be submitted to the production management team.

The production measurement team would review the data and determine whether or not it's appropriate for use at federal and Indian facility measurement points.

And it was appropriate, it would be put on a - listed our PLM Web site under a pick list of that type of device. Once somebody submits the data or request and the BLM approves it, if, let's say, one operator decides that they want to use this new technology and they submit the data for it, once that happens and it gets posted on our Web site, as an approved device anybody can now use that device without additional approval.

You know, we believe this would tremendously increase the consistency of review and the other advantage we see to this is it would provide a mechanism for us to accept new technology without having to rewrite the regulations.

For example, one of the difficulties of (Entra) Orders 4 and 5 being sold, (Entra) Order 5, for example, doesn't even discuss electronic flow computers. It's chart (recorders) (unintelligible).

Well, if we have this production management team, new technology can be submitted over and above what's in the proposed 3174 and 3175. It could be reviewed by the production measurement team and it could be approved, thereby, we believe it would increase the longevity of the regulations and make them much more dynamic and much more adaptable to new technology.

Orders 4 and 5 will take a cookbook approach. Here's a cookbook of how you measure gas - requirement one, requirement two, requirement three. We just do those things and you're good to go.

But there are no performance goals. Nowhere in (Entra) Orders 4 and 5 that they say here's what we're trying to achieve with all of these cookbook items. What we're proposing is that we would establish, in addition to - we're going to maintain a cookbook approach or we're proposing to, for certain technologies like (orifice) plates and electronic flow computers and PD meters and Coriolis meters.

We're going to retain a cookbook approach to some extent but were also going to explicitly say what our objective is, what is - what are we trying to achieve in terms of uncertainty, certifiability and other things?

The idea of the performance goals would be to balance accurate and verifiable measurement with economic considerations. So the performance goals, as you'll see from (Mike McLaren)'s presentation and mine, are tiered to volumes.

So lower volume meters have fewer - are much less restrictive than requirements for higher volume meters. We believe, in addition to the production management team that I just (measured), we believe this will also result in a much greater amount of flexibility for operators and manufacturers.

If someone proposes a new meter to us, for example, and it goes to the production measurement team, these performance goals are what that production measurement team is going to use to approve or disapprove that device.

So as long as you meet X percent uncertainty and verify - and our ability to verify that technology, you're good to go. You'll get listed on the Web site and no further approvals are needed.

Part 3170 has proposed changes common to all three orders. One change is the current requirements in all the orders apply only to operators. Right now, we have authority only over operators.

We inspect against the operators. Any violations we find go to the operators. Well, one problem is, that I hear this a lot - is, let's say we're doing and audits on a specific gas meter.

And so our auditors will send a written order to the operator for the lease in which that gas meter is located requesting information - volume statements, config laws, calibration statements, all that stuff in the operator says, "Well, that's not my meter. That meter is owned by the pipeline."

So the operator goes to the pipeline and they say, "Can you provide us information because BLN is doing an audit and they've required us to submit it." And the pipeline company could say, "No, we're not providing that information to you."

Well, our only enforcement action is to write an incidence of noncompliance to the operator. We have no authority currently over purchasers, transporters and pipeline companies.

What we're proposing is to actually activate statutory authority we already have through the Federal Oil and Gas Royalty Management Act and for record-keeping only, record-keeping requirements would also apply to purchasers and transporters through the point - the royalty settlement point which basically means the FMP, the Facility Measurement Point, or the point of first sale, whichever comes first.

So with this, when we do an audit, for example, we could go directly to the purchaser or transporter if they happen to own the meter we're auditing and request that information that we need for the audit.

And we could take enforcement actions directly against purchasers and transporters. Currently the orders have a variance section specific to each order. They're similarly worded but they are not identical.

What we would propose is to remove the variance section in each order or each subpart and put it in the part itself, Part 3170, and also we would further explain how you would apply for a variance and how we would review it.

And with that, I'm going to turn it over to (Mike Wade) discuss the requirements of 3173.

(Mike Wade): How's this working right now? Can we hear everything? Thank you. That is the intent. Okay, under 3173, the proposal is to cover some of the new areas - are off-lease measurement, co-mingling, FMPs and, of course, site security.

Currently, Order 3 has absolutely no guidance or requirements for co-mingling or off-lease measurement. And we were proposing the direct procedures for co-mingling and off-lease measurement and to - methods for providing the information to us for approval.

Specifically what the BLM is looking at in the proposal, is first off, any instance where the co-mingling has no impact on royalty, all federal, all Indian, same ownership or interest rates, et cetera.

No problem. We can do those - almost a rubberstamp, if you will. I don't like that term but it's relatively simple and straightforward to take care of. No impact on (unintelligible).

Then we have the low-volume exemptions for commonly. If you have low volumes, there are reasons to co-mingle to make it more economical to approve the co-mingling.

And then finally we have exceptions based on extenuating circumstances. Those can vary all over the place, but you have that ability to request co-mingling approval for those, but you have to justify it.

BLM is planning and proposing to review existing co-mingling and off-lease measurement approval at the same time as you request the FMP number. So it's not too cause dual applications, extra work - try to minimize some of that.

Order 3 certainly applies to all sales and allocation meters. All the requirements for gas measurement applies to all those meters. Royalty measurement is not even discussed in Order 3.

And we would propose to apply the new regulations only to those points where royalty is actually determined and also for a facility measurement point. And you ask, why do we need a facility measurement point? We've had many instances where we've done production accountability over the inspectors have gone out to witness reader calibrations, et cetera.

Come to find out, six months later, the meter we witnessed for the meter we started working on is not the meter the operator says is their sales point. And we've just wasted tons of time for the operator, tons of time for us and accomplished nothing in return.

This will make all of us working from the same location for sales and for royalty purposes. Run tickets are currently in Order 3 for oil measurement and including some additional information on seal numbers, water drains, et cetera.

All that's required now on a water drain, for example, date on, date off, seal number, basic (reason), drain water, no other information. What we're proposing is that the documentation for, like, water, hot oil and et cetera to include some new information on your part.

How much was in the tank before you broke the seal? How much was in the tank when you finished draining or when you got rid of the hot oil? How much did you leave in the tank? How much did you actually remove?

Also we would be moving run tickets into 3174 with the oil measurement which (Mike Maclaren) will talk to you about later. End of month inventories were beginning of month inventories are currently not required.

It's very much a useful, necessary piece of information. We're proposing operators to an end of month inventory and maintain the records. We have no requirements and the orders right now for Royalty 3, also known, beneficial use, used on lease - all treated basically the same. Have the same meanings.

We're proposing is to add some requirements with the site security diagram for the operators to provide us, if they're going to claim beneficial use, give us some information. How are you going to determine that volume?

What methodology are you going to use? Are you measuring it with a meter? Are you basing on the equipment, BTU ratings, et cetera? Tell us how you're doing it so that we're all on the same page.

Certainly we have a requirement for a self-inspection program in Order 3 and for a site security plan that you have that the operators are supposed to maintain and (rework).

We are wanting to eliminate those. With the additional information on water drains and all the other requirements, that will totally replace that so there's no reason to have both requirements and this as well.

Things that we would like specific comments on if you can provide it to us in that - and it's mentioned in there is, on the co-mingling side, we have a 10% rate of return number. Basically that would be in relation to the equipment that you would add.

If you did not get the co-mingling, the new piece of equipment, is that 10% of the number? Is it a bad number? Is there a better way to make that determination? We basically need more information from the operators and people that have to do this work.

We're asking for comments on the timeframes and volume thresholds that we're using for implementation. Current basic proposal, in general, says high producing cases would require to report or request their FMP number in the first nine months.

The middle third producing cases - this is based on an annual monthly average - what have the next nine months and then the low-volume, very low volumes, what have the final nine months, or 27 months just to request the FMP.

Is this too long? Are our volume thresholds too low, too high? We need more information on what the operators think and so we can do a reasonable time of the implementation without too much difficulty. And I will now give this over to (Rich). Or, I'm sorry, to (Mike Maclaren).

(Mike Maclaren): Hello. I'm (Mike Maclaren). Can you hear me okay? Okay, there we go. I'm (Mike Maclaren). I'm going to talk about the proposed technical changes to Subpart 3174, the oil measurement.

As (Rich) stated, currently on the onshore - currently in the onshore report, there are no overall performance standards stated. It's a cookbook. You could either use a (lag) system or a manual (unintelligible).

So what we propose are some performance standards for uncertainty, is basically we proposed three levels of uncertainty. If your meter is measuring more than 10,000 barrels a month, we're proposing a plus or minus .35% uncertainty.

If you're measuring between 100 barrels a month and less than 10,000 barrels a month, we're proposing plus or minus 1% uncertainty. If you're less than 100 barrels a month, we're proposing plus or minus 2.5%.

And where we got these numbers from, the top one, the plus or minus .35%, is based on an uncertainty calculation we did using a current (lag) system under the onshore report utilizing a positive displacement meter.

The middle layer, the plus or minus 1%, is based on an uncertainty analysis using manual gauging on a 400 barrel tank. And for that number there, that was withdrawing 200 to 300 barrels of that 400 barrel tank on the load out.

And then the bottom tier, (before) low producer that was calculated removing, I believe, it was 40 barrels out of the 400 barrel tank. The current order for it references industry standards that were published in 1989.

We propose to incorporate 21 of the current (API) standards and two of the AFTM standards. The current order for it requires a pressure vacuum (D patch) or event (live) valve for tanks.

We're proposing, along with the pressure vacuum (thief hatch), we're proposing require a pressure vacuum release valve to (level) it out at pressures greater or less than that of the (thief hatch).

Also in the proposal, we're stating what we want, a condition of that tank. We wanted to maintain pressure vacuum integrity. It's implied with the equipment in four, but it's not stated. We're explicitly stating the condition we want that tank to be in.

The current order for it has requirements for caging and sampling in random order. We propose is, in Order 4, we're proposing the sequence for manual tank gauging along with the requirements for each sequence.

That's based on the current API 18.1 standard. The current Order 4 requires a manual tank gauging two consecutive gauges within a quarter inch. We're proposing the current API 3.1 standard of two consecutive identical gauges or three gauges within 1/8 inch.

The current Order 4 requires tank calibration tables with no increments specified. They're in typically a quarter inch to match the gauging. We're proposing 1/8 inch increments of the tank capacity tables to match the new gauging requirements of API 3.1(8).

On the current Order 4, (lack) systems require an automatic temperature compensator or automatic temperature gravity compensator and only allows the use of positive displacement meter.

We're proposing to prohibit the use of automatic temperature compensators for the automatic temperature gravity compensators and require the use of the temperature, the electronic temperature averager instead.

And we're proposing to allow our Coriolis meter in lieu of the PD meter if the operator chooses to do so. That current Order 4our requires measurement by tank gauge or the (lease) automatic custody transfer (lack) systems.

So we're keeping the automatic tank gauge and the (lack) system in there and we're also - have a section proposed for a Coriolis measurement system, separate section for a standalone Coriolis measurement section.

And we have a few requirements that we propose for the Coriolis measurement system. We're proposing to maintain the 8400 volts per barrel for the minimum resolution. We got some specifications including reference of accuracy, the influence effect, stability, pressure drop.

We look to Coriolis to have a non-(recitable) (totalizer) that the PD meter has. In the proving of the Coriolis, we want to clarify a meter zero prior to approving the Coriolis meter.

We want the Coriolis meter to be able to determine that standard volume. We've got a couple options we proposed for gravity in the Coriolis measurement system, whether it be a composite sampler, (work stream and) gravity or the average gravity as determined by the Coriolis meter during the flow between run tickets.

We have a list of some on-site display requirements which is basically the raw data pressure temperature flow rates. And for the audit trail, we're posing the requirement of quantity transaction records, configuration law, rent log, alarm log.

Current proving for a (lack) system, if you're less standard or equal to 100,000 barrels, quarterly. If it's greater than 100,000 barrels, it's monthly. We're proposing proving for the (lack) and Coriolis measurement systems to prove every 50,000 barrels on the totalizer or quarterly, whichever would come first.

We came up with that 50,000 barrel number during a statistical analysis on a - as a volume threshold that the cost approved good equal the royalty overpayment or underpayment on the - based on the difference in meter factors between provings.

Currently, Order 4, the proving section has no standards for prover sizes, no standards for prover conditions and no standards for (pulses) during a proving run. We proposed minimum and maximum fluid velocity for the prover sizing.

Who would like to proving to be a normal flow rate, normal pressure, normal - the normal API gravity. And if you're using a small volume prover, you're not going to get 10,000 pulses on a run. You're going to get a couple thousand, three 500.

And so if you use a small volume approver, if you're getting less than 10,000 pulses per run, we're proposing to require pulse (interpolation). Currently there is no measurement ticket requirement for a (lack) system. We're proposing to generate a measurement ticket after proving of either the (lack) system or the Coriolis measurement system, and at the end of every month.

So winding down the oil measurement, in the preamble discussion we're specifically asking for data and comments on volume uncertainty levels that we proposed.

Explained where we came up with our numbers. If you guys don't think is a reasonable, if your calculations show different number, we would love to see that.

At the time we drafted the roles, we had no data on the automatic tank gauging systems, any kind of hybrid tank measurement. We've got a few since this has been published, proposed, we're hoping to get a lot of field test data, a lot of input from you guys on the use of automatic tank gauging for possible inclusion into the final rule.

We proposed on composite sampling system on the Coriolis meter. For sediment and water determination, what we're proposing is if you don't have a composite sampling system, and we wouldn't allow deductions for sediment and water because we wouldn't be able to determine if you didn't do a sample.

Now, there's - we're asking for input from you guys. Are there other ways to determine sediment and water other than sampling? We could definitely consider.

Ways to address meter factors - if you have variable flow rates, fluctuating pressures, different gravities, how would you utilize a meter factor, which averaged meter factor, proof is a different flowing condition and average that meter factor in between provings?

Would you come up and calculate a dynamic meter factor with the flow computer? Would you use a dynamic meter factor and adjust for the different flowing conditions? That something we're looking for input from you guys on, on a way to address that. And with that, I will turn it over to (Rich).

(Richard Estabrook): Okay, will finish out this presentation with 3175. Currently onshore Order 5 approved only orifice plates and mechanical recorders. Order 5 is a cookbook on how to measure gas with orifice plates and mechanical recorders.

We did address electronic gas measurement systems with our statewide NTLs that again, are unique for each state office jurisdiction. All the NTLs are the same with the exception of Wyoming.

Proposed 3175 would maintain the orifice plate as the primary method of measurement. We like orifice plates because they achieve reasonable accuracy and perhaps, more importantly, they are completely independently verifiable by us.

We would still except mechanical recorders with some exceptions are restrictions. We would accept or approve approved electronic gas measurement systems.

And we would have specific guidance or alternate measurements and flow conditions. Like Order 4, Order 5 also has no performance goals. It's just a cookbook.

And Order 5 past three tiers of requirements and I have a little graph I'll do in my next slide. Proposed 3175 would actually establish for tiers of performance standards based on average flow rate as follows.

So this is actually what's in Order 5 right now. So the average monthly flow rate is shown on the Y axis here. If your meter is measuring more than 200 MCF per day on a monthly basis, currently under Order 5, all the 26 or whatever requirements there are in Order 5 are in effect.

If your meter measures less than 200 MCF per day, you no longer need a continuous temperature recorder. Again, this is with the current Order 5. If you are less than 100 MCF per day, you also are exempt from the requirement of the DP, the Differential (Pen) to run in the outer two-thirds of the charge and you're exempt from the data ratio, and that's the .15 to .7 beta ratio limits.

Proposed 3175 takes this concept and expands on it a little bit, these tiered requirements. We would establish for new categories of FMPs, or Facility Measurement Points, based on average monthly flow rate.

If your meter measures more than 1000 MCF per day, we would call that a very high volume FMP. As I recall from our statistical analysis, about 1-1/2% of all of our readers would fall under this category right now.

If your meter measures between 100 and 1000 MCF per day that would be called a high volume FMP. If your meter measures between 15 and 100 MCF per day, we would call that a low-volume FMP. And less than 15 MCF per day, we would call that a marginal volume FMP.

So for each category there would be requirements specific for that category. And the idea is, that for high-volume meters, like very high-volume FMPs, a little bit of measurement error has a big impact on the royalty you pay because there's a lot of volume going through that meter.

So what we're proposing is we would be very tight with that meter, very restrictive. Other restrictiveness, of course, comes with a price tag. And so the idea is, as the volume gets less and less, first the risk of royalty mismeasurement also becomes less and less because it's just not handling that much volume.

But also you want to provide some form of economic relief as the volumes, those meters measured get lower and lower. So we're very tight - the proposal will be very tight with the very high volume meters. As you get down to marginal meters, we have almost no requirements for that matter whatsoever.

The performance goals are uncertainty in both volume and heating value. They also include bias or the absence of bias. And they also address something that we call verifiability, one of the very critical things - our ability, the BLM's ability, to independently verify every angle step of that measurement.

So the report 10,000 MCF was removed from a lease in a given month, we can verify that yes, in fact, that is a reasonable number that represents the gas that actually went through that meter.

For very high-volume FMPs, we're proposing an overall volume uncertainty of 2%, an overall annual average heating value uncertainty of 1%. We would not accept any statistically significant bias and all measurements - all aspects of the measurements would have to be verifiable.

For high-volume FMPs, the volume uncertainty would be 3%. The uncertainty in average annual heating value would be 2%. We still would not accept any statistically significant bias. And the measurements with still have to be verifiable.

For low-volume FMPs, we would do away with uncertainty requirements altogether. We would still not allow any statistically significant bias in the measurement would have to be verifiable.

For marginal volume FMPs, the only thing we would care about is some level of independent verifiability of that measurement. These are the overall performance goals.

The cookbook part of 3175, uses these performance goals in this concept to figure out what specific cookbook requirements would apply to each category of meter.

Order 5 currently adopts one and only one industry-standard, and that's AGA Report Number 3 and specifically the 1985 version of AGA Report Number 3. And that talks about orifice plates and flow rate calculations.

The proposed 3175 would adopt the latest API standards covering primary devices, orifice plates in particular, electronic gas measurement systems, slow rate volume and heating value calculations and gas sampling and analysis.

Current (Entra) Order 5 has no inspection requirements for meter tubes. Now, API 14.3.2 goes into a fair amount of detail about requirements for meter tubes, surface roughness, roundness, obstructions and so on.

We believe that, because API 14.3.2 has specific requirements for meter tubes, clearly it's an important thing to (measurements), that we should be expecting those meter tubes periodically to make sure they comply with API 14.3.2.

The proposed 3175 would have some requirements for meter tube inspection - meter tubes inspections and the frequency would depend on the classification of the meter. So what we're proposing is this schedule. For marginal volume FMPs, we would not require any meter tube inspections. The low volume FMPs would require a visual inspection once every five years.

A visual inspection would be probably with something like a borescope. You wouldn't' have to disassemble the meter tube. You can run a little fiber optic thing down through a pressure tap and see what's inside that meter tube. High volume FMPs would require a visual inspection every two years and a detailed inspection once every 10 years.

A detailed inspection would be complete disassembly of that meter tube and miking of (brownesses) surface roughness measurements and so on. Enough stuff to verify that that meter tube objectively complies with the API 1432 standards. So very high volume FMPs, we are proposing a once per year visual inspection and a once every five year detailed inspection.

Also, if a visual inspection identified a problem, that could jump it into a detailed inspection to correct that problem and make sure it complies. Currently, an (unintelligible) Order 5 which only discusses mechanical recorders, Order 5 - mechanical recorders are the only thing that it talks about. Proposed 31-75 would still allow mechanical recorders.

But only for those meters measuring less than 100 MCF per day. We do not believe that the performance, the uncertainty of mechanical recorders is well enough to find to even do it on certain recalculation. And because high and very high volume FMPs have an uncertainty standard, there's no way we can do an appropriate calculation to determine if a mechanical meter - a mechanical recorder was meeting that standard.

As I said before, (unintelligible) Order 5 has one and only one requirement for heating value. And that is that it's determined at least once per year. In the proposed 31-75, we would establish the following sampling frequency. Marginal volumes would maintain the once per year standard. Low volume FMPs would have a twice-a-year, once every six months fixed sampling frequency.

For high and very high volume FMPs, we're proposing something a little different. Initially, a high volume FMP would have to be sampled once every three months. However, once we had enough samples to do some statistical analysis, the frequency of spot sampling could either increase or decrease based on the heating value variability of those past historic samples.

We put this in here because we realize that sampling frequencies are somewhat arbitrary. And in order to try to avoid arbitrary sampling frequencies, we went back to overall performance goal of the 2%. And the heating value would be adjusted to meet that plus or minus 2% uncertainty of heating value. So very high volume FMPs, the same principal would apply. Initially, it would be once per month. Once we had enough data, enough samples to do some statistical analysis, we could increase or decrease that sampling frequency to maintain an overall certainty and heating value of plus or minus 1%.

The proposed 31-75, this is continued. If you could not meet the uncertainty requirement based on sampling because you'd have to do it so frequently to get to that 2% or 1% level, we would then require the installation of a composite sampling system or online gas chromatograph. We are proposing that all gas samples, all gas analyses I should say that are used in the determination of royalty would be submitted to a BLM database called GARVS - G-A-R-V-S.

That's the Gas Analysis Reporting and Verification System. This could be key entered or it could be downloaded from your software patches like FLOWCAL or whatever. This GARVS system among its' functions would be to do the statistical analysis to figure out what sampling frequency is required to meet that 2% or 1% uncertainty.

Order 5 has no requirements for sample location or method. No requirements for gas chromatographs. Proposed 31-75 would have a few new things on this. Now this first bullet point I'll just say right up front, we're just kind of throwing this out there. And as you'll see in our request for data, this is one of the things we're looking for data on.

What we're proposing is that the sample probe be located 1 to 2 times dimension DL, downstream of the primary device. As you know DL is the minimum length of downstream meter tube required in API 14.3.2. Now this is in contradiction with API and GPA standards for placement of sample probes.

And the reasoning is - again, we're open to data on this and other opinions. The reason is that API and GPA sampling standards are based on an assumption that you're at or above the hydrocarbon due point and that basically you're free of any kind of entrain liquids. We're pretty sure that the reality is most - at least these level measurements, there is some entrained liquids there.

Hopefully, not a lot. And we feel that sampling systems designed to eliminate those liquids, this would include the use of membrane filters on the probe. Would not adequately account for any entrained hydro carbon liquids that are flowing through the orifice meter. We think perhaps that by placing the sampling probe relatively close to the orifice plate would actually because of the velocity and the turbulence coming right through the orifice plate on the primary device, that might actually lift those liquids or put them into the an aerosol stat that we can then sample.

And we believe that could be a way to account for entrained liquids going through the orifice point. As I say, we're looking for data on this. This is just a proposal. Proposed 31-75 would allow for spot sampling methods. So an empty helium pop, floating (unintelligible) and portable gas chromatograph. We would have requirements for gas chromatograph calibration and operation.

And another proposal we have is if the hexane plus analysis yields greater than 0.25 (unintelligible) percent of hexane plus, that you would be required to get an extended analysis through C9 plus. Order 5 has no requirements for BTU reporting. BTUs can be reported on a number of different basis. They can be gross or net. They can real or ideal. They could be dry, wet or as delivered.

And they can be reported to a number of different pressure basis. I've never seen anything besides 60 degrees on the temperature side. So what this means is for a single sample, you can actually - I think you'll be doing a multiplication. For a single sample, you can actually get 60 different BTU values potentially.

So it's not real ideal. Dry/wet as delivered, different pressure basis. Right now, we have no requirements for which one of those 60 you should be paying royalty on. So Proposed 31-75 would say gross, real, dry, 14.73 and 60. Order 5 and the state wide NTLs have no requirements for independent testing of transducers or flow computers.

Basically, all transducers and flow computers are accepted. The problem with this is that the statewide NTLs already establish an uncertainty standard for electronic flow computers. The calculation, the tool that we use to calculate uncertainty, their uncertainty calculator uses manufacturer's reported performance specifications for transducers in particular as the basis of the uncertainty calculation.

We believe that a lot of that - or some of those manufacturer specifications are based on proprietary in-house testing methods. We believe that that - in order for our uncertainty calculation to actually mean something, we should be using specifications and performance standards that have been tested in a transparent, publically available methodology. So 31-75 is proposing that all transducers and flow computers use that high and very high volume FMPs.

Must go through a testing protocol. The production measurement team that I mentioned earlier would review the results of that testing and develop a list - a tick list of approved transducers and flow computers. This would be a one-time shot. So for example, if a manufacturer went through the testing protocol and submitted that testing to the production measurement team, the production measurement team did a review of that and said, "This is an improved device" and put it on the tick list, no one else would have to do it.

Once it's done, it's done. And that piece of equipment is approved. Some specific data and comment requests for 31-75 and just be aware, when the pre-ample gives specific or asks for specific information. The reason we do that is because we know we're putting something out there that we don't have a lot of information about. And we really are looking for data on this to help us decide whether it's a reasonable - something reasonable, something that's not workable.

We really are looking for data to help us figure how to deal with this. So a lot of these things are just proposals - are true proposals we're just putting out there. So specifically, these things appear at a pre-ample of 31-75. What is the cost industry for type testing transducers? We don't a god feel for that. We're looking for some information.

What is - in the proposal, we wouldn't just test one transducer and base performance specs on that one transducer. We'd want some kind of a statistically representative sample of transducers to do that testing on. In the proposed rule, we're suggesting 5 is the magic number. But we have no idea if that's correct or meaningful.

Should we require standards for online gas chromatographs? There's not much out there that I'm aware of for industry standards on online gas chromatographs. So if there's other documents that we should be incorporating, we'd like to know about it. There is the new API 22.6.

Is that appropriate for incorporation in this standard is the question. The next one gets to the dry/wet as delivered issue. There's been lots of controversy about this. We currently - our policy is to require dry. Our proposal in 31-75 is to require dry. A lot of companies say, "Well, the as delivered method is more appropriate because we know that there's water there."

And the dry and the as delivered in my opinion, as delivered means it's an assumption. You have to make some assumption of the water vapor because it's very difficult to test for. The as delivered assumption is that that gas is saturated with water vapor at meter pressure and temperature. So dry and as delivered are basically the end points. The maximum and minimum amount of water vapor that can actually exist in the gas sample.

Well, the truth probably lies somewhere between those two points. So, if industry - if you want to claim as delivered (unintelligible) value, we would like some data to show that that's a legitimate assumption. If we don't get that data, we would be leaning towards the dry which we're proposing right now.

Data showing correlations between sample probe placement and composition. That's that requirement, the proposed requirement I talked about. The 1 to 2 times dimension DL. We're just throwing that out there. We're really looking for data on that, for anything. Anything you have because there's really nothing in literature that I know of.

Costs of retrofitting orifice meters to meet the eccentricity requirements of 18.4.3.2, again, we didn't have a good feel for this one. One of the things would be - that we're proposing is that mechanical recorders, chart integration statements would also have to be done to the 1992 calculation method. We know a lot of chart immigration companies are - have been around for a long time and may not have upgraded.

We have no idea what the cost for a chart integration company to go from the 85 to the 92 calculation would be. And finally, data showing the difference between C6 plus or hexane plus and (unintelligible) plus analysis is a function of C6 plus (unintelligible) percent. Basically, we're looking for any kind of data that would support or refute our .25 malt percent threshold to go to an extended analysis.

I have up here - that's the end of the presentation. I have up here, if you haven't seen it already, there's mailing addresses for comments. I would go to this site right here, this regulations.gov. Not only can you submit comment there, but you'll also find a copy of the proposal itself. You'll also find the economic analysis, the environmental assessment and we did a study on heating value variability which is the basis of our proposed sampling frequencies.

And that study is there as well. These PowerPoints will be posted at this site right here on.doi.gov, the bottom one.

Woman: Thank you. We'd like to take - I have a signup sheet for speakers. And currently, I have 12 speakers. And the last I heard, there were 57 people on the phone. Now I don't know if all those 57 people want to speak. But we don't know until - you know until we ask. If you have not signed up to speak, please do so.

Let's take a 10 minute break because it's about 120 degrees in here. And come back in 10 minutes, and we'll start with the speakers. Thank you. Okay. Let's get started. Sir, I'm going to interrupt you. It's okay. It's okay.

Man: After these gentlemen...

Woman: I know. Well, you can come back up here as soon as I get out of your way. Okay. Thanks very much for taking a quick break and coming back. I'd like to start with these speakers now please. And we've had a little shuffling of speakers. So if you feel like you're interest in speaking. Please I'll ask again at the end if you'd like to.

So thanks for coming back. Our first speaker is Dave Curtis. Are you Dave Cutis? Well, how about a microphone?

Dave Curtis: Good afternoon. Is that working? My name is Dave Curtis. I'm with Anadarko Petroleum. First of all, since I'm the first speaker, thank you all very much for taking the time to do this forum. This type of stuff is important. It gives us all an opportunity to hear your thoughts and for you to hear you know what we're thinking.

Along those lines, again, we appreciate the fact that 3 and 4 got extended. But I'd like to take this opportunity to request that we get the same for 5. It would be my argument, I don't know about others here. But 5 is some of the most impactful rulings to us under current operations. And so additional time to be able to review and more importantly collect the data that we talked about in order to either agree with or refute some of these things.

And even better would be to have perhaps some workshops where we can sit down and talk these things out. Sometimes in written form, we all lose something in the shuffle. Okay. That being said, I just have a couple of questions and thoughts on a few things here. One was on the heating value variance versus uncertainty.

It talks a great deal about meeting that uncertainty there. And then it lumps variance of the heating value (unintelligible) uncertainty. We collect the sample under a certain sample collection technique. We analyze with the same instrumentation. And we use the same calculations and reporting. Uncertainty is the same regardless of the variability.

So the two don't really tie in. We have a high heating value well in Colorado that's getting major ambient temperature changes. We're going to see major variation in our heating value. But truthfully, that has nothing to do with that same less certain. So I'm not sure that that really tracks with one another. Does that make sense?

Well, our suggestion's in there. You know there's no real good way to collect that variance. As you start to get lower where economics don't support putting in a heated composite sampler or GC. We agree with you completely. And when we get our major delivery points, that's where we start going into putting in those composites and GCs just it's at a higher threshold because it's not only just the price of purchasing that equipment.

For those of you who have run on heated composite samplers, when you're running on a rich gas to run that heater, those things do not work worth a darn. So you spend a lot of labor hours out there trying to keep those operating. So when they're in remote locations, what we're even deeming currently at high volumes just doesn't become economically feasible.

So anyway, that was my thoughts on that. C6 versus C9 plus, you'll see we did a study on this. We did a host of samples. And what we found that on our sample set, if you look at the repeatability spec cited by one of the major manufacturers, I won't say it here. There percent of heating value repeatability that they site on our study, the heating value change between doing a C6 plus and C9 plus calculation is actually the average is about half of that repeatability.

So it's well within the analytical deviation of the instrumentation. We did have one outlier. And that's cited in our data. So we hope that you take the opportunity to look at that because I think that's important because moving to C9 will have a major impact on us. And then the last one I'll make, then I'll give it to somebody else. When you're up there and saying about the dry.

You said dry versus wet, that currently, it would only be accepted as dry. And I just want to clarify in the proposed rule, it says dry or actual measurement. That still is the case, correct? Okay. Just want to verify because that threw me in a loop somewhere where we were going. So anyway, appreciate the opportunity. And I'll turn it over to the next person.

Man: Oh, yes. Please. For the record, I agree with what you said. The actual is still in there. It's just realistically, I can't imagine too many people are going to go out with a chiller (unintelligible) or laser device on a well.

Dave Curtis: I can speak for our company. Since this brought up I don't two or three years ago, we've implemented it. And every one of our folks that are out there with a portable gas chromatograph which is almost everybody on a federal property is out there with an automated chill (unintelligible) in real. We haven't been applying it yet. But we've been collecting all that data though.

Man: Alright. Thank you.

Dave Curtis: And by the way, you're right. It shows some degree of partial saturation, more than 50%. So it does kind of lend more towards a as delivered value being more accurate than a dry. But it is some degree of partial saturation.

Man: And is that data that you're looking to submit with your comments?

Dave Curtis: You know because we were agreeing with yours, we weren't really going to submit it. But if you'd like it anyway, we could.

Man: I would love it.

Dave Curtis: Okay. Yes, we'll put it together.

Man: Great.

Dave Curtis: I may send it offline if they've already sent our company's comments. Not offline, but you know what I mean.

Man: Thank you.

Woman: Thank you. Stormy Philips.

Stormy Philips: First let me thank you for (unintelligible) to follow you guys all over the country. It's very fun to drive from Durango to Oklahoma City.

Man: You are going to Dickenson I assume.

Stormy Phillips: Yes. I had a question for (Mike). I'll let you guess which one. I just wanted to know the reasoning or justification that the BLN is using in requiring the sample point to be downstream of the Coriolis meter and upstream is approving connection on a Coriolis measurement system. It just isn't in line with normal lack design.

Man: The sample point?

Stormy Phillips: Yes. In the component requirement section, 3174.10 Section 3, No. 8, it says, "The components must be placed in this order." And it places the sample point after the meter.

Man: Yes. And I believe that does following the sequence of the API 5.6. I'll verify that. But it should have been following the sequence in that diagram on API 5.6. I'll verify it. But that...

Stormy Phillips: Already done. Already over it. Yes. Just trying to understand that because when you look at your normal lack set up, you normally have the sample point somewhere upstream of the divert vale which is going to be upstream to the meter. So that could create an issue in which right back to asking for variances on all the lack systems.

Man: I'll look at that because I thought that sequence was following API 5.6. So I'll verify that. Please you did submit that comment.

Stormy Phillips: Yes.

Man: Thank you.

Woman: (Harry Calser).

(Harry Calser): Thanks. First of all, I apologize. I signed on a signup sheet. And I thought it was a regular signup one. And later, they said it's the one you're a speaker at. So, now I have to speak. So, one comment I guess on 4. There's not near as much information in 4 as there is in 5. 5 goes in talking about all the requirements for testing of transducers, RTDs, all of that.

There's not mention of that in 5 - in 4. I'm not - I guess in my mind, I'm assuming the same thing applies. That somehow, they all will have to be tested as well if they're on liquid. There's no mention of that. So that's questions we've been having and been wondering. There's also come up questions about the list of approved devices with liquid.

How do you get on that list? Coriolis for example has not been used now is not on that list. How do you get on that list? Is there a testing protocol? What's it going to involve for someone to get on the list for the liquid equipment? On gas, you know I feel for all the producers in here because I think it hits them much harder that it does us.

But we're also partners with them. Anyway, we want to consider ourselves that. There's a couple of those that hit us pretty hard and it indirectly then is going to hit them. And primarily, the testing protocol of the transducers and transmitters. The way I read that the big one is the stability test. That's a 24-week test.

The way that's stated that says, "Every range. Every model." If you do range downs, every range down. I do not have an exact quote now. But we have estimates of that test running around a half a million dollars for one range. We don't know facilities that can do this. We do know Southwest Research has a couple of large walk in chambers. We know (CZ) has a small one.

We don't know where we're going to go if we have to go to an independent third-party facility to test the sensors that you're going to need to use on your leases. That's a six month test. So once this becomes law, particularly in the economy we have today, we're not going to be going and investing money to begin this test until we know what the test is.

So, if testing is done, once it becomes law, we know what the tests are and it's a 24-week test for every range, we have five models for example of one range, the 250 x 500. That's five different sensors that are going to be tested with five of each. That might be a $2.5 million charge. Someone will be paying for that.

Not knowing the facilities. Not knowing how we can get these done and how we can get that done on any timely basis particularly if an effective date is 30 days after this becomes law, we don't see how you're going to have equipment to put on your sites. We would propose that some method be implemented that manufacturers can do this testing.

Whether that means a PMT. Whether that means an (ISO 9001 auditor), someone can audit our facility. You can sit and watch us run the tests. Odds are, we have better equipment than any of the labs do that would be doing this. We have many more chambers. We've got 13 chambers we can be doing these tests in. We don't know of anybody together that has 13 chambers.

We're open to that. But we believe there ought to be consideration that they be some independent that can audit us and say "Yes. It's okay for you to do the test. We'll watch you. We'll look at your test results. We'll verify your test results." So that one is a very big concern of us. I'd like to see that the calculations of the flow computer be allowed that way as well because I think it'll make it less expensive for everybody.

And we're open to showing that to people. We don't - you know we don't want to just come back and have people see anything that's really proprietary. But following some test procedure and seeing the data and verifying that our test equipment is precise enough equipment, we're very open to that. One thing I just thought of now, one of our guys read through - I've not read through the details of trying to track when it says it supports different standards as reference.

There is one that's an IEC standard in there that appears that that stability test is DP at pressure. If that's the case, that's going to limit anybody that can do that to almost nobody because there's very few facilities that are going to have environmental chambers that can run a DP and a pressure at the same time. We can do that. But it's going to be at ambient conditions on one device.

Those are not the common thing you're going to go down the road and buy. I think that's primarily mine. I appreciate the opportunity for this. I've got comments that I'm sure will be filed as well. And appreciate it. Thanks.

Woman: (Unintelligible).

(Harry Calser): Oh, yes.

Man: Can I just ask one question. I know this long term stability thing has been an issue for me for a while. I was hoping 22.4 would address it, but I don't think they are.

Man: Not very intentionally, it's not.

Man: You know that - the long term stability test in the proposed rule was pulled pretty much from an IEC standard. You - do you have any idea how - is it a European thing? How they implement it?

Man: No. I believe that's the (Leon) - the one (eon) was referring to that when you go and look at that test, it lists the DP for elevated pressures. And accurate test equipment that can do 200 inches at 500 pounds is few and far between.

Man: But do you know anybody who is implementing that IEC standard? I don't know all those standards. I'm sorry.

Man: Okay. Thank you.

Woman: (Dee Hummel).

(Dee Hummel): Yes. Sir. Yes, sir. I was wondering if you could verify how you determine the volume thresholds. For instance, in a scenario I look the other day, we had one well that flowed at 1000 MCF for one day. How is that determined?

Man: But that's actually spelled out in the proposed rule. And I believe it would be an average - it would be a monthly average taken over the previous 12 months or the life of the meter, which ever was shorter I guess.

(Dee Hummel): Okay. I'll take a look.

Woman: (Unintelligible).

Man: I could (Anne) like I typically do. But in the pre-ample, there's at least one place where it says it could be yesterday's volumes which doesn't make sense and doesn't go along with the other partner. What you said is exactly right. It's the last 12 months or the volume on the (unintelligible) whichever's less. You know but again, there is some disconnect there.

Man: Okay. Thank you. I'll check that.

Woman: Thank you. Fred Young.

Fred Young: Kind of service at home. So, the - so I'm an engineering managing. But there's a lot of experts on measurement in here and I'm not one of them. I never - I never claimed that. The - we are going to submit written comments.

And for the record, Enterprise is not a car rental company, we are the second largest pipeline company in America.

We have about 49,000 miles of pipe. And we have about 25,000 gas meters and a significant number of them are on DLM land. I have some specific comments and I have some cost data that I thought went to your - one of your comments you requested about numbers on the AGA 3 compliance. And I'm going to use a work you don't like a couple of times and that's grandfathering.

But you're going to have to just sit down and not jump out of your chair, okay. First, we do thank you for this. And I understand why you want to update them. But we think they go - the rules in general go past the update. Our specific concerns are the fact that regardless of how your system performs, there is no allowance for using the existing equipment, i.e. grandfathering.

There - there are unintended consequences of some of this on system - on an entities accounting systems that are going to take time to implement. The time of this whole regulation - set of regulations to be implemented is a concern. Cost is a big, big concern. Obviously, we're a transportation company. We think there's somewhat of a discriminatory treatment of transporters because we're not an equity owner.

And all the economic analysis was based on equity ownership. And in our case, there's no improved performance for many of these proposals. And lastly, there is a risk of revenue loss to the government from - in our case and to the Indian tribes and other equity owners. So let me - we're a publically traded company. So I can't give you exact specifics.

So I got - I had this scrubbed. And here's what I can do is we're a - suppose there's a hypothetical transportation company with 100 gas wells. And I'm going to speak strictly to gas. 40% of the meters are going to have - the meter tubes are going to have to be replaced because of either inspections or AGA 3 noncompliance.

A meter rube right now, shop fabed, is about $8,000. We're running about a 2-1/2 to 1 multiplier to install it. There's another 40% of the tubes that are going to have to be modified. And because these things are out in a less than high populated, high density areas, it turns out to be cheaper to replace them with shop fab meter tubes than to go out and modify them.

So we're looking at of the 100 meter tubes, 80 of them being replaced. That's a cost of about $2.2 million. Electronics, I talked to (Mike) about this, (Mike Wade) a couple of weeks ago. Our read of this FNT requirement and I understand why you want it is that the only way we'll be able to get to assure the FNT exists on not only the station and drawings but on any document or report you get or might get or could want is that it will have to reside in the flow computer.

We also have to have our own tag name in there to meet our Instrument Society of America requirements and our own internal policies. There's no - we don't know of a single flow computer installed today that will accept an 11 character tag name. We have one that'll do 10. But none will do 11. And none will take two tag names.

In addition, we have perfectly good working flow computers now that are - had been out of manufacturer for a number of years. They will not - we don't think they'll make it to the approved equipment list because how are you going to - how's the manufacturer who doesn't make them going to send them in for testing.

So we're looking at 100 flow computer changes which is about $875,000. Flow computers are $2,500 apiece. We've have gone through this pretty (unintelligible). The other pipe modifications based on minimum pipe tubing sizes and blah, blah, blah, we think we're going to s be spending about $87,000 on this 100 meter company. Or this 100 meter company would.

Gas chromatographs, this company'd have to - would have to buy an additional gas chromatograph because of the increase in samples. That's at $70,000. Personnel, it's going to take more people to do the inspections and to run to catch the samples and to run them. So for this 100 meter company, that's about a $300,000 - two people, $300,000 per year cost when you're fully benefited.

They're going to have to buy vehicles. It's going to take another 4 wheel drive, 3 quarter tone whatever heavy duty truck. And that's $70,000. We're going - the company's going to have to buy a borescope. They're $60 grand a piece. The accounting system this is not the biggest cost, but it's a killer in terms of time. The first FN - if I read this correctly, the first FNT the company receives, you have to be in compliance within 30 days.

It's going to take 2 years to modify a mixture of major vendor, software and home grown software and accounting systems because all the accounting systems, volume accounting systems have to be modified. And at the end of the day, the total cost is about - for 100 meter company, it would be about $4.2 million.

The interesting thing is if I talk now about Enterprise specifically, we measure the gain/loss on all of our systems. And we looked at the last 12 months, BLN systems. We're within a quarter percent gain/loss system wide. And we measure systems from the well head to - all the way to Mount Bellevue in some cases.

But on the BLM specific equipment, we're within a quarter percent. So for $4.2 million, nobody's going to get anything. In fact, if you look at - if there - because measurement is inaccurate, there's not a direct - you know you can't count 100.00 molecules yet. There is a risk of plus/minus that at the end of the day, you know in fact right now, we're showing that we're over accounting for gas delivered from BLM meters.

There's a chance that we would say, "Well, we got better measurement. We're not paying you as much because the volume went down." So, we would be out this 100 company - 100 meter company would be out $4.2 million and could - and everybody could lose. So - yes, ma'am. Two things. There's safety concerns here because of the amount of pressuring and depressuring that goes on in field while this work's being done.

That's an increase in personnel exposure. And there's supply problems because last year, the BLM - n BLM lands in New Mexico, I think there were 920 give or take wells completed. You all have 66,000 meters in service. How many of them are going to get - how many meter tubes are going to get replaced?

Who's going to make them? Who's going to install them? Who's going to house the people installing them? And who's going to provide the flow computers? We're going to all be scrambling for the same first one out of the box. And we don't see any way to support that effort. And I guess lastly, we would say if you all - you know we think that there should be some sort of grandfathering based on performance.

I don't know if there's better ways to say grandfathering then don't raise your hackles. I understand that. But there ought to be credit given for systems that are performing well. And if the intent of BLM is to have a database, it would be cheaper on everybody for BLM to develop its' own server and database with company information and well information and lube numbers so that the BLM is on the same page as the vendor rather or the producer, transporter whatever than however many entities are developing their own systems.

Woman: Would you like to respond to anything that was just said? Anybody?

Man: The only thing I would like to add is have you submitted this in writing before us? Or are you planning on it? Thank you.

Woman: Can I just add something to what you just said? Now, I know nothing of what you're talking about. But what I think is important is that when you express your concern, generally, I think if you have a solution, you probably ought of throw that at it too because they're looking for all the information that they can get. Then the solution might be helpful.

Okay. Good. Thank you.

Man: So one quick - some of your numbers surprise me. And again, I hope we'll get this in writing. But, basically you're saying that you have to replace 80% of your meter tubes. And not to talk about it here, but I'd be really curious as to what is triggering that.

Fred Young: A number of things. One, remember we are - we do measure within a quarter percent. (Unintelligible). When you inspect, if you come out that you don't meet all the exact criteria in terms of smoothness or roughness, however you want to say, the eccentricity if I could say that right, the orifice plate, all those things, if you now go into - if you don't meet it, you have to replace the tube.

There's no question. You go from the 385 to the current AGA 3, if you don't have the tube bundle in there, there is a difference in length between the two meter runs. And that is even more expensive because now you've got to move block valves and you've got to figure out how to depressure more than just the meter tube.

Does that make sense?

Man: I think so. I would hope to get that specific information now as part of your comments.

Fred Young: Okay.

Man: Yes. That would be helpful.

Woman: Thank you. (Dean Graves).

Dean Graves: (Rich) was hoping I wasn't going to talk. Dean Graves with Devon Energy. And as you can guess, I've got a few questions and comments. (Rich) and I go back a way this way. In reading the document, a lot of detail, on Order No. 5, been very engrossed in it recently, making sure we're putting (unintelligible) our statements together.

And this is the scenarios I'm having to tell my management. I've got a well that flows 101 MCF a day, older well. The air tube was put there in about 2000, maybe a little later. The - it's on a plunger lift. The - I am making some liquids with a separator and dumping, worse during the winter time. To comply with the document - to comply with the document in my experience with these documents, based on our experience with the NTLs, what is being proposed will become the law unless you all make a change to it.

That's the way it's being written. So the way it's written right now, to - when this comes into effect unless I change the meter tube and replace the meter tube, replace the EFM, I might shut it in. I cannot flow it because there's nothing been approved. I have to meet the approval list that the BLM is going to provide.

There is zero meters on that. So, at this point right now, when it becomes law, and after six months or 101, it'll be 12 months. If there's not something there for this particular equipment that I have on the EFM, I shut it in. I will have to change the meter tube because it will not meet the eccentricity requirements that are stated on the 2000.

Hence, I am making liquids. I am very likely to record (unintelligible) percent the 6 plus. I am also likely having a variability in my BTU greater than 1% or 2 %. So I will be - have to install a composite sampler if not an own line chromatograph on a 101 MCF a day well to keep it flowing. The cost for installing the tube $8,000 as you all show in your document for your rate of return, is just a bare minimum.

It didn't include the connection fee. It didn't include the work doing it as Fred was saying. And the EFM. You add all that together. It's easily between $25 and $50 grand to make those changes right there. The adding a C9 online chromatograph to comply with your requirement and the heating element, you may be upwards of $75,000 to comply there on a C9. The - then you add to it - I'll bring my data into flow cap.

Flow cap, (P gas), whichever one it is. I would not be able to supply you data because you will not allow that for the pre-ample from the flow cap. And that's what the pre-ample says. And so I've got to find a different way to get the data. It looks like the way it's written, that I will not be able to do editing even though it seems strange.

But that's sort of the way I can be interpreted by an inspection of the data. The other thing is if my meter is connected by regular tubing and a manifold which I'm not sure how much those costs because of the existing 3/8ths will not be acceptable for the document. The - the concept that Fred mentioned in his scenario is we see 80% plus of all meters above 100 MCF a day will have to be replaced.

Meter runs, EFMs, right now EFMs do not comply. The amount of data you're looking for. The size of the FMP. Even though the FMP number is a good concept. The cost of putting this is going to be well exceeding the economic. But we've also found is that we get zero return on doing these. And the other thing that we see is the concept is to improve uncertainty.

Very, very noble. Totally agree with the concept and uncertainty. The BLM document in the pre-ample calculates the 15 EMF of 15 MCF a day on the concept of rate of return of 15% and a cost of equipment of $8,000. He cost of equipment is between $25 and $50,000. Rate of return is different than that.

The 15 MCF a day becomes very (unintelligible). That's really an arbitrary number. The numbers above that is pure arbitrary and will be (unintelligible). There's no justification on how they're achieved. We are - a company has put together a document to show a suggested rate of return on how that could be - not a rate of return, but a calculation on how to do that - to return that.

And so we're suggesting a different tier - tier levels based on numbers. Not just pulling numbers out of the air. The other thing that we're seeing is the uncertainty concept. The uncertainty concept is equated in the pre-ample shows that justification on the 15 MCF a day as if the uncertainty improvement is going to gain volume, gain revenues. Whoever.

Uncertainty is if there's an error, it can go either direction. Okay. So uncertainty says there's a possibility of error. And so if we're trying to achieve a 1% or in the case, it's 101 MCF a day at 2% uncertainty, that assumes that there's a 2% error which there may not be. But if there's an error, it can go either way.

The true there is no true rate of return, no body gains dollars by accomplishing this. Accuracy can be improved. But it gets to the point of exceeding the ability. When you get to the BTU, you get away from uncertainty until you get to the variability of how it's all written. The concept of I've got a well out there that's making some liquids in the separator, my BTU will swing.

If it swings 101 MCF a day - if it swings, if it's showing 1150 and it swings 30 throughout the year, that means I might have to put a composite sampler on or maybe an online GC. I have to wrap up. I just got started. Okay. So bottom line is the way it is written, we will be shutting in - we'll have to to comply. Shutting in these locations because we'll not be able to meet them.

The cost of doing this is extremely expensive. The rate of return for us is almost zero. And so, we ask that you look at these things. We understand what you're trying to accomplish. We understand trying to get the accuracy. But when you start ting and get to down to the (unintelligible) detail, this is tremendous and what it means to us.

So. Okay. I hesitantly will quit. They say I'm always that way. I'm sorry.

Woman: Thank you. Kathleen Sgamma.

Kathleen Sgamma: Thank you. Kathleen Sgamma with Western Energy Alliance. And, you know, we really do understand what you're doing I totally agree. We're, you know, we all have an interest in accurately measuring our products. So we do share that goal. However it's (hard) to see right now with 2,007 pages and yes I'm (that anal) that I do count these things of open regulations right now between BLM and EPA with onshore order 9 coming. It's hard to look at some of these regulations and not see sort of a punitive nature about them.

We had asked for all of the onshore orders including onshore order 9 coming up to have overlapping common periods. We do appreciate that onshore order 3 was reopened. However when you really look at it it was an extra 17 days for one of those regulations. So I don't think we've got enough time for both industry and BLM to do what it's trying to do with this very complex technical regulations. So we would ask for not only more implementation time but more time to respond to these regulations.

And I think, you know, your staff is feeling the strain as well. Sure more time commenting. Well we had asked for 90 days of overlap for all of the onshore orders all four of them that was probable - I mean I understand that might have been too much but certainly 30 days of overlap with 9 I think we're all struggling to understand these regulations we're all struggling to understand how they would be implemented. We're struggling to understand, you know, I think your point was a great one and I would frame it instead of grandfathering as not being so retroactive.

You know, you look at things like details like providing equipment numbers to the facility measuring points retroactively. I mean how many producing wells does BLM have systemwide something like 90,000 right? Ninety four thousand. I mean it just is a lot of retroactive applications or implementation that is indeed going to shut down production. It's looking at trying to track down hypothetical losses and royalties which will result in actual, you know, shutting in of royalties.

So it's that being penny wise and pound foolish as we try to track down to a very specific degree. And again we all appreciate and understand the need to be accurate but when we're chasing a few million we're putting billions at risk. So that's kind of what we're struggling with right now and it's been a while since I read the GAO report in conjunction with the first round on onshore order 3. But I mean was there a display of willful - a willful - is there evidence of willful, you know, cheating on measurement?

Is there really a problem with industry really not reporting? I think we try - our members try to report as accurately as possible to pay an equitable royalty. But again we're getting to these very specific regulations and I appreciate (Rich) that you're, you know, there's more performance based standards in the new regs there's still a lot of that cookbook. And you look at is that cookbook really providing the value especially when you're looking at the cost of that retroactively.

So, you know, we have a desire again to accurately measure to make sure that we're bringing regulations up so that new technologies can be used and will be flexible for the future but we still see a little bit too much of that cookbook. And I would like to bring up the issue of comingling because I understand from the Durango session that the idea there is to retroactively go back and cancel communitization agreements.

And I'm trying to - I'm really trying to struggle with or we're really struggling with understanding why, you know, that system of CAs would want to up end that whole system because again that's going to shut in quite a bit of production again resulting in less royalties not more. Yes, yes I think so that would be great.

(Rich): I'll give a (unintelligible). I think with the CA issue there's I think there's some like mass confusion there. I think there might be some confusion on that one. So I think one's bought up on Durango and I just want to make it really clear. So if you have a CA a communitization agreement and that communitization agreement has multiple properties on it some federal some state private whatever the production from that CA even if there's more than one well is - that's not comingling.

Okay that - it's all based on the CA. So comingling from our definition is the combining of multiple sources prior to the royalty measurements. A source is an uncommitted lease or a unit participating area or a CA or a non-federal property. So again if you have a CA even though there's multiple ownerships in there that's if you measure the production anywhere on that CA that - there's no comingling with this happening. The same with a PA a participating area.

You can have a giant participating area with 100 wells on it and 50 different properties owners. If you measure once all of the production coming from all of those 100 wells if you measure all of your measurement points right at that PA boundary there's no comingling there's no approval required. So I want to make sure that's really clear. A CA is a source and as long as you're not combining that source with another source there's no comingling and no approval required okay.

Kathleen Sgamma: Yes and perhaps I hadn't misunderstood the feedback from Durango because I thought it was stated that many CAs would be rescinded as a result of this process?

(Rich): Not communitization agreements if that's what you're...

Kathleen Sgamma: Okay.

(Rich): ...I'm assuming that's what CA stands for.

Kathleen Sgamma: Right.

(Rich): No in fact communitization agreements or units are great ways to avoid comingling.

Kathleen Sgamma: Okay.

(Rich): Yes we would encourage those. Yes, yes and there was some confusion there.

Kathleen Sgamma: Okay because I heard that was a hot topic of conversation. You know, when we read onshore order number 3 we looked at it as, you know, almost a non-(seneschal) result and maybe it's the way it was worded whereby, you know, it was - I mean the whole point obviously is to bring together multiple (owners).

(Rich): In fact...

Kathleen Sgamma: Multiple ownership.

(Rich): ...yes we'll look at that we'll look at clarifications if that's confusing the language is confusing.

Kathleen Sgamma: But why go back and again retroactively look at all of those agreements? You know, why not just move forward? I think that was one of our main comments and will be of all of these, you know, and with the reopening of three as well.

(Rich): Okay and, you know, and we'll definitely consider that comment. If I could just make a general comment? You know, we hear this a lot on Durango about how these regulations would shut down a bunch of wells and cause a lot of economic hardship. If that's what happens and we have failed miserably in these regulations because we don't want that that's exactly the opposite of what we want to happen.

So if that's reality for the producers out there then what we need because we're not - I don't think any of the three of us up here are - have ever been an operator. We don't know what you go through. If that truly is the case - excuse me - we need to know what are the provisions that are especially onerous? Why are they onerous and can you provide which would be really helpful is can you provide a different less costly way for us to achieve what we're trying to achieve?

Yes that would be enormously helpful to us because I'll state it flat out. If you guys will start shutting in our wells because of these regulations then we have completely failed in our mission. Our mission is to get revenue for the production of our oil and gas and obviously if we get less production and less revenue that would be silly. So...

Kathleen Sgamma: Well we - I'm sorry.

(Rich): ...no I was just going to say so please help us the non-operators up here understand what is the - what are the onerous regulations why their onerous some data would be helpful and why the cost and (Dean) and (Fred) both I think they're going to give that to us and again how can we achieve the goals we're trying to achieve in a different way? That would be very helpful.

Kathleen Sgamma: Okay and we certainly will in our comments. I think implementation time especially if it's retro. I mean would say don't go back retroactively from 94,000 wells let's look forward to the future let's make sure it's less prescriptive and more performance based. But I think there needs to be more time if there is going to be that retroactive element I think we need a lot more time.

I think some of the comments on, you know, just getting some of this equipment would suddenly create a bottleneck because there wouldn't be enough manufacturing supply. So certainly we will comment. I appreciate the ability to provide comment today. I'm wondering if you can share a little bit from the morning session with the tribe. Are they concerned about, you know, how this would affect development? Do they understand, you know, some of these shut in issues?

(Rich): The session this morning was mainly a listening session. I honestly did not get a lot of feedback.

Kathleen Sgamma: And Durango the same thing or?

(Rich): We got some feedback in Durango and I think some of those concerns were shared but I wouldn't swear to that.

Kathleen Sgamma: All right thank you very much. I guess I hear you about saying put it in writing but I would just add again and, you know, perhaps after being on the receiving end of lots of regulations just this year not just from BLM which is starting to feel like a, you know, an onslaught to us that when you look at the time to implement this before the election next year it kind of strains (unintelligible) to think about how that can all actually be done for some very complex regulations.

And conjunction of course with onshore order 9 coming up which will be completely new set of requirements. So we're feeling a little shell shocked we're feeling a little bit as though, you know, we do put things into our comments and like the hydraulic fracturing rule we did see improvements from the first draft to the second to the final but still many things that, you know, make us wonder, you know, how do we implement this and how can we continue to operate on federal and Indian land. Thank you.

(Liz): Thank you. (Kim Fairchild). Okay we do appreciate that you're making the comments and like you talked about the fracking rule we did go through all the comments we got a lot of them but we went through them and so thank you for acknowledging that. And we hear your point. Right now this is when the comment period ends and it sounds like you all have thought through at least some comments so please give us the comments you can and thank you for doing that and coming here and we'll really look at it seriously.

(Steve Wells): Hi (Steve Wells) I'm out of the Washington Office I work with these guys. Just for a little more context we glossed over it it is in the preamble but why we're here today too is this has been going on for quite some time. 2013 we did a stakeholder Web forum (Rich) basically conducted that. The idea was to get it out on the table things we're looking at to address measurement accuracy precision those kinds of things.

And we welcomed that feedback that helped us guide this but if you go back even further in 2007 there was a royalty policy committee had a bunch of recommendations for the Department of Interior you need to do this, this and this. In 2010 we had so the government accountability office came to us and said you know what you need to tighten your standards out there. But we all knew that these regulations from 1980's needed some help and we needed to update it.

But they gave us specific guidance the office inspector general also chimed in. In 2011 the Department of Interiors put on the high risk for production accountability. So it isn't just our decision here we're trying to find the best fit like (Rich) was talking about how can we achieve these measures? And I think the words we're hearing from some of the consultants here (Devin) and others and pipeline company is maybe the threshold should be changed. Maybe the phasing period should be changed.

And this is why this is the economics. This is the impact. Those are the things that we're asking for data on that you can provide to really help us out to make the best rule out there. But I don't think we can say we're just going to leave it as is. The reason we're on this high risk is because of these existing properties out there. The GAO was not so worried about what's going to happen with the new well that comes in in 2017. They're worried about the 23,000 producing properties out there and ensuring that we end up getting a proper royalty accounting.

Whether it's up or maybe it's down we know that it can go either way on those errors. But the idea is that it should be accurate it should be defensible. We should have documentation when we do these audits we can defend it. So there's a lot more to it. I know we kind of glossed over it with some of the slides for background and in the preamble if you want to read through all those documents. But we do explain a little bit more of how we got here and really how important it is to have that kind of feedback and the data.

If you can share data this was a proposed rule based on what you told us from 2013. So we're hoping that our final rule will incorporate the things that you say you know what you guys were close but you need to do this much or do this differently then we're willing to hear that. So that's why the proposed rule is out there. We're trying to give you as much time as possible but we've had some very good comments. We had an outreach at the API meeting so that we could explain some of these things and get comments.

We've been getting comments in from some of the companies already. So we have some very good stuff already but anything else that you can provide between now and December 14 would be awesome. Thank you.

(Liz): Okay.

(Kim Fairchild): (Kim Fairchild) with WPX. Everybody's hitting on gas measurement and - sure - everybody is hitting on (gas) measurement and I deal with a lot of oil on the order of 35 hundred run tickets per month and that's a lot of gauging a lot of paperwork that goes on with that. The thing that concerns me is this changing the tank strappings from a quarter inch to an eighth of an inch. I did some little calculations while you all were talking. On a 12 foot diameter tank it's either a 210 normally it's a 210 or a 400 barrel tank.

That's 1.77 - excuse me - 1.667 barrels per inch if it's a perfect cylinder. If it's on a quarter inch gauging the accuracy is 99.76 to go to a eighth inch it's 99.88. Yet on your (LACT) meters and unfortunately you went through that slide too fast for me to write it down but I recall a .35% accuracy on a 10,000 a day (LACT) in at 1% on a 1,000 and 2% on a 100. Now you ask where did I get those percentages on my tank straps? Average load ranges from 170 175 barrels on a single truck.

Then there's other trucks that'll actually pull they have a little tandem and they can do 280 it depends where you are Wyoming or if you're out in New Mexico DOT regulations. So you can see if it's a 280 barrel that goes the accuracy is phenomenal it's better than your gas measurement. I mean (Dean's) right. And the other thing is I can take anybody in here and he and I can go walk up on a tank we can both gauge and I guarantee you we will not get the same gauge within an eighth of an inch.

And so if you're sitting there worrying about that eighth of an inch it might be high one time it might be low the next time let's flip coins and guess what it's going to even out and be very accurate. You know, I don't see where this kind of thing is gaining the BLM any extra revenue for the US. And to gauge to go out and strap a tank in Wyoming for a quarter inch is $3,000 per tank. I've got 600 plus tanks on federal lands.

So and this is at current prices because I don't know what they're going to charge me to go out there and put in four gallons and measure it four gallons and measure it four gallons and measure it. But $1.8 million for what? What do we gain? And let's go to thresholds because that was brought up. Our wells start out especially these unconventionals let's start out $2 and $3 million a day 1,000 barrels of oil a day they're on rapid decline very rapid decline.

Within six months they'll be at half of that rate or even lower. I don't think anybody here will argue that. So what criteria? Where's the threshold? That threshold we're moving through the thresholds very quickly so you're asking me to go put all of this equipment all of this expense on a brand new well that's going to be down there in the very low range in a very short time and now I have to maintain that equipment with text it's, you know, it's crazy. And then back to somebody said grandfather.

I have I said I I'm responsible for probably 150 very low volume wells that are scattered all over New Mexico can't afford this. So we'll end up shutting them in unless it saves us the acreage that's critical for development and now you've lost that revenue and you'll never get it back.

(Liz) Okay...

(Rich): I'd like to just...

(Liz): ...oh sure.

(Rich): ...like well we came up with the (unintelligible) we - what we did was implement the current industry standards the (API) 3.18. Now if we can get comments with data saying don't do that that's what we want. Again we just looked at the current industry standard when we wrote that that's where that eight inch came from. So please submit that data in your comment that's if we can get data saying eighth inches and feasible we're definitely going to consider that. Okay.

So and I think we can justify if we're not going to follow in industry standard if we can justify that with your comments. But I can't honestly propose a rule that's not following an industry standard with no justification. So I appreciate your comment. Thank you.

(Liz): Okay thanks very much. I don't know whether I'm supposed to sing this next line? There's an Operator somewhere and we are ready to take questions from those on the phone.

Coordinator: On the audio portion to ask a question please press Star 1 please unmute your phone and record your name clearly when prompted. One moment please. And as a reminder to ask a question please press Star 1.

(Liz): Hello.

Coordinator: I'm showing no questions at this time.

(Liz): Okay sure we're coming back to - well we're working our way around. Who wants to speak? Is there anybody that would like to speak that has not spoken? There's got to be one of those. No all right we can work - oh I saw somebody.

Stormy Phillips: (Unintelligible).

Robert Frtiz: Exactly right. You already talked Stormy I've got just a couple of questions in general.

Stormy Phillips: (Oh).

Robert Fritz: Robert Fritz with Enable Midstream. (For) the distinction between transporters and operators from what I have seen from the onshore orders you're not making any distinctions at all and I'm not sure exactly where we've fallen at. In other words if we're picking up gas from a BLM from a meter at a BLM site are we as transporters are we responsible for the same level of paperwork and everything with regard to that meter and volumes and all of that as is the operator?

(Rich): First let me ask if it your meter?

Robert Fritz: Yes.

(Rich): Okay then the answer would be that you would be responsible for all the recordkeeping the record retention requirements that the operator would be.

Robert Fritz: The same thing as he would be. Who answers to you? I mean are you going to go to him first and then come to us? And also on all of that we can't go back to like Flow-Cal or B gas or whatever or our homemade system and pull the data wouldn't you come to us on that?

(Rich): The proposal is that we want raw unedited unmanipulated whatever data from that meter. So it would have to come directly from the Flow computer or if we can get assurance from third party software companies that we are in deed getting raw unedited unmanipulated data we would be willing to accept that.

Robert Fritz: For how far back?

(Rich): Well the law this is in law not even a regulation is seven years for federal six years for Indian. Now there's some additional requirements for record keeping if there's a traditional action going on but the basic standard seven years federal six years Indian.

Robert Fritz: For raw unedited data for hourly data?

(Rich): Well yes whatever there is out there. You know, we normally require daily records.

Robert Fritz: Okay even daily records.

(Rich): And again the record retention requirements for seven years and six years is statutory that's federal oil or FOGRMA Federal Oil and Gas Royalty Management Act established a six-year retention for everybody the Royalty Simplification and Fairness Act in 1996 came back and said for federal we're going to change from six years to seven years. So we have no flexibility in that whatsoever.

Robert Fritz: Okay the next thing is move that back probably more on the liquid side if the operator is either tank gauging or has his own meter for the wells he's collecting from the BLM land. And then downstream of that we have a (LACT) meter and skid where he is selling to us and we're putting it in a pipeline are we then still required to for the same recordkeeping and the same BLM requirements as he is as his meters?

(Rich): My question would be which set of meters is royalty being paid on?

Robert Fritz: I would assume it's his.

(Rich): Then that's where the obligation stops. Okay.

Robert Fritz: And then my final quick question if I might. I can talk as much as (Dean) can. Almost as much as (Dean). Not the great (Dean Graves). Anyway seriously on the implementation of API standards we were talking about this earlier with tank like tank agent an automatic tank agent that's an excellent example or with API 14.1 you were talking about that with gas sampling. It's not the data and the research that's available from the API that they based their international standards on acceptable?

You're and you're looking at me strange (Rich) the...

(Rich): Okay I'll...

Robert Fritz: ...(justification).

(Rich): ...speak for the automatic (tank) gauging.

Robert Fritz: Yes.

(Rich): Okay API has a standard out there. See there was a company who took the automatic tank gauging and they tested it and they tested it on private leases comparing it with the manual tank gauging and they did find there were certain conditions certain configurations it wasn't working for them. They were planning different mixers different results from different mixers different results from different sample locations and they were piecing them together until they could come up and meet - they (unintelligible) they were with the manual tank gauging.

And then with that they presented the data to the OM office in Colorado and got a variance to use it. But that's the testing that we were talking about and that's the data that we're asking for. And on that particular one they used a float gauge they didn't use a radar gauge. There's a company in Montana right now doing the same testing they're using a radar gauge they're using a different mixing system different sampling different temperature determination.

That's when I talk about requesting data that's what I'm looking for. That's what we're asking for.

Robert Fritz: I would submit that all of those things that you just indicated would need to be the mixing for the temperature stratification is just as important as manual tank gauging as it is with automatic tank gauging.

(Rich): Right and that's with they're comparing is the manual tank gauging results with their reference as a hybrid tank management system. Different methods determine temperatures. Are we getting the same results as dropping the wood back in the tank? The sampling the mixing sampling are we - but what part of the flow through that line are we going to take a sample and get the same results as…

Robert Fritz: Okay well that would be process we're starting...

(Rich): ...right, right...

((Crosstalk))

(Rich): ...and that's what if we...

Man 1: (Unintelligible) we're starting to get (unintelligible) a little.

(Rich): ...okay but if we implement that into order it's going to be the hybrid system the whole process is...

Robert Fritz: ...oh.

(Rich): ...what we would be looking at and we would be looking at it from an uncertainly based standard is the overall the automatic tank gauge the sampling process the temperature is that all going to either combine uncertainty. And so that's what these two companies they're doing two totally different hybrid type systems is what they're comparing against the current manual tank gauging to receive the same results the same temperature the same API determination the same grind out that's what they're looking at.

And that's what I....

Robert Fritz: (Unintelligible) I kind of think...

(Rich): ...with that I'm looking...

Robert Fritz: ...it really doesn't have anything to do with the gauging and yet...

(Rich): ...it's...

Robert Fritz: ...the standard says you - we will not have automatic tank gauging. If you have everything else the same and you gauge the tank manually or you gauge the tank with an automatic tank gauging.

(Rich): ...all right if - so the intent of why people want to go to automatic tank gauge is to get people off the tanks. Okay it's - where's the benefit if you use automatic tank gauge but they still have to go up on the tank and take a sample?

Robert Fritz: Oh no...

(Rich): Yes then take...

Robert Fritz: ...no yes well that's...

(Rich): ...the (test) but...

Robert Fritz: ...not the way that way the.

(Rich): ...right and so...

Robert Fritz: Or is…

(Rich): ...what people are testing out there and what we're hoping we can get in the final role is a hybrid type tank measurement keeping people off the tanks get people off the tanks.

Robert Fritz: ...I see.

(Rich): That's the data we're looking for.

Robert Fritz: Okay I see where you're coming from it's not just the gauge and it's...

(Rich): No it's the...

Robert Fritz: ...the process.

(Rich): ...whole process.

Robert Fritz: Okay (Richard). Yes you've said initially that you were basing all offshore order 5 on all the latest international or API AGA GPA standards. But in like your requiring for C6 plus for the 603010 and the GPA standards says you use 603010 only if you don't have better data.

(Rich): Well I...

Robert Fritz: Yes we have better data and we then say no we don't want to use 603010.

(Rich): ...that's a comment that we would consider.

Robert Fritz: Okay.

(Rich): Yes okay.

Robert Fritz: She's told me to shut up now. Okay.

(Liz): Okay we had a couple of other hands up. I.

Stormy Phillips: The same time...

((Crosstalk))

Stormy Phillips: ...I actually just have some more clarification questions Stormy Phillips WPX Energy. One is during the royalty determination slide that you showed at the very beginning you showed that the volume metric and the heating value had equal standard or effect on the royalty rate. Why is that you decided to have a higher uncertainty level on the heating value as opposed to volume metric measurements?

(Rich): Part of it was what we thought was reasonably achievable. The 3% is a number that we've been using for over 100 Mcf per day now for a number of years since the statewide MPLs came out. Again the proposal is 2% for over 1,000 Mcf per day. We think that because normally those high volume wells or high volume meters were flowing much more consistently and often measuring a more processed product that we could do better on that. Again we're open for comments on that.

The heating value again we're talking about average annual heating value on certainty which I've equated with variability and we can talk about that more too. That - those uncertainty standards are to certainly proposals were actually based on the way or the cost of obtaining those uncertainty levels meets the risk of under or over payment in royalties if that makes any sense. That was the basis of a lot of the thresholds we used in order 5 and I think in order 4 as well.

Stormy Phillips: In an effort to reduce some of the strain on transmitter and equipment manufacturers would the BLM would be willing to approve the release of existing data for review by the (PTM) or (PMT) rather than reconducting the test?

(Rich): We - I mean sure. Yes we take a look at the existing data and see if that meets what we're looking for.

Stormy Phillips: And one last question involving the performance measurement team. It seemed to me or even in what you stated that a big purpose of that is to try to stay up to date with new equipment as it comes out however some of the areas especially gas measurement that we've had the most technological growth in has been linear meters which in the standard are only going to be accepted on a case by case basis still requiring variance. Since that's likely to be the area of the most technological growth this is that kind of counterproductive to the (PMT) idea.

(Rich): Well again that's the proposal in the rule. We still have issues with linear meters as far as verifiability. If in the comments if we were supplied enough data to satisfy our discomfort with the verifiability aspects of linear meters we could certainly consider an alternative. And even with the proposal it would be a case by case approval of linear meters and the (PMT) would be doing that as well. But on a - only on a case by case basis application specific.

Stormy Phillips: And there's no consideration for documents like AGA report numbers 7 9 and 11 that address those styles or at least the three examples used in the document?

(Rich): I mean there certainly could be. Again our main concern of linear majors is the verifiability aspect. And I don't know I'm actually not that familiar with those documents. And if there's - if our verifiability concerns could be addressed then yes it's possible that we would consider that.

Woman 2: Over here.

Fred Young: One question. Fred Young Enterprise Products again. So the I think everybody here prefaces with understands, you know, we're the government we're here to help you concept when I read these documents and do - we've heard a number of references to API and GPAs and AGA standards today from you all. There appears to be a cherry picking or some other phrase of those documents. And part of me wonders what is the basis for that because it and I don't - this is going to really sound bad so please bear with me okay.

It feels like you all are saying or the BLM is saying some of these documents are good and some of them the BLM knows better. And that kind of flies in the face of the basics of those documents because there's been a lot of work on them. And, you know, and I can look at specifically in Chapters 4 and 5 of the API and PMS where sections were specifically excluded. But it's through a number of chapters. And I'm just curious why if you're going to use those document - if you're going to refer to API and AGA and GPA why aren't those reports accepted from stem to start?

(Rich): From the order 5 standpoint we actually carefully read through all of the standards that we were accepting either at whole or in part on the gas measurement side. We excluded parts of some standards that were written in a way that we could not directly enforce or that were general statements that really were unenforceable and not standards at all. So we really wanted to focus on those sections of the API standard that we could implement and enforce specifically.

So that was the case in a couple of ones that I worked on on the order 5 side. Some cases we took standards and made and modified them a little bit to make them more enforceable just - I don't - the one that comes to mind is the upstream and downstream life tables and API 1432. This is kind of trivial but those tables are a little confusing they're a little hard to use because instead of getting data ratio ranges like from .2 to .3 here's the requirements.

From .3 to .4 here's the requirements its they give the notes .3 .4 .5 so how do you use the tables? So we added something into there to make it clear how you use the table. I hope we did it right and if we didn't I'm sure we'll hear about it. But that's the ideas because we were very deliberate in going through each one of those standards and making sure that we are only incorporating those parts of the standards that were relevant to our mission. Like some of it had safety stuff in there that without a safety agency so we've excluded those.

And that we could specifically enforce.

(Liz): Thank you. Operator it seems that we have a caller on the phone.

Coordinator: Our first question today is from (Ron Gibson). Sir your line is open.

(Ron Gibson): Thank you gentlemen and buddies I appreciate you giving me the opportunity to speak. I've got several concerns I want to try and minimize as many as I can. Let me touch on the areas that maybe have not been touched. One of the discussion points (Rich) that you had mentioned was sampling probe spot being even in your document and even in the case that it's going to end up essentially being 2.8 to 9.0 pipe (unintelligible) from the (unintelligible) meter.

And this is in Section 3175.113. My worry card is and even as you guided - indicated in the regulation it's different than API 14. And I'm not confident that even 80% is going to be enough to cover all the meter tubes that we're going to have to replace for some of our (beta) ratios because obviously you're going to try and go for the 2.8 size which would none of our tubes would work. So can you give me some indication of what the intent is?

One of the things that I heard you say was that the closer you are with the sample port to the orifice plate your intent is to hopefully pick up heavy (unintelligible) that maybe coming over and look at phase and by the time it gets to the sample (port) it may be air solid. I have a fundamental problem with that because we're not trying to measure two phased liquids and liquids is specifically tried to exclude. It feels like the transporter company the transporter is being penalized possibly because of inefficient separation that's (trimming the meter).

So I have a little bit of heart burn with that. I have a little bit of heart burn with the - just the gymnastics of how you guys are going to approve all of the different pieces of equipment that are going to come into you in a timely fashion such that we as operators will know which pieces of equipment are going to be acceptable and which ones not. And in that time leg are we subject to minor and major violations and penalty assessments? Because you guys haven't got all the data resolved and on the board and even the (GRV) - (AV) is not functional yet.

Is your expectation that the meter manufacturers and the trans - the manufacturer equipment and manufacturers are to supply that data or is that just come from the Operator to approve different pieces of equipment because we don't have the ability to do that it would cost us a tremendous amount of money to do that. It should come from the manufactures but let's not call it out in the regulations.

And then finally my worry card is is that the concern about what (unintelligible) corrections and assumptions we have not been able to find some equipment that can accurately measure water vapor at pressures less than 100 pounds and any effective and economical fashion and trying to understand why the assumption of fully saturated.

Granted there are times when it possibly could only be personally saturated but the assumption of fully saturated which is just working in the past for a very long time even as (Fred) has mentioned it to you but, you know, our accuracy percentages on our (L &U) is very low on some of our (damaged) systems. Why that is no longer acceptable method? Because I don't think we're going to be able to monitor water sampling water and take water samples on all of our meter leases.

(Liz): Okay that was a big long question (Ron). Let's give it to somebody to answer it or them.

(Rich): Well first (Ron) why aren't you here? You live in Oklahoma City I think.

(Ron Gibson): Well unfortunately yes I should be there. I just came back to work just the other day. I've been off some time...

(Rich): Well (unintelligible), you know, as I mentioned all of the API or (VAPI) and GPA standard on sampling is based on the assumption that there's no liquids present. And I think we all know that's not really true much of the time maybe most of the time especially at least level measurement. And our intent is with that proposal is there a way that we can fairly account for those liquids those little droplets of liquids that are going through the orifice meter and not being accounted for by the traditional API 141 or GPA gas sampling methods?

That's the intent there's - if there's no way to do that then there's no way to do that. And part of this was our discussion at the Midwest Measurement Conference a couple of years ago. You know, we had that panel discussion about wet gas sampling and there's no - there's nothing even on the books to even experiment on what gas sampling and (unintelligible) sampling. So this was a simple attempt to try to address that and again that's all it is. We're looking for data on it. We're looking for comments and input but that is the intent.

If I wrote down the second one correctly is, you know, we're going to have to internally figure out the implementation of how the production measurement team works and no I can't imagine they'll be any penalties if you couldn't meet timeframes because the production measurement team wasn't in place or it wasn't done with their reviews yet. I can't imagine that would happen.

Who submits the data? I don't think we care. I'm assuming it makes more sense from manufactures to submit the data than operators but if an operator wanted to submit the data for a particular transducer than we would accept that just as we would from a manufacturer.

The water vapor correction again the dry assumption is one end point that's the minimum model water vapor that can be there it's fully saturated and has delivered not the wet one. Is the other end point the truth is somewhere between I'm guessing. And we don't believe that we should take a royalty hit for an assumption or fully saturated when that is essentially I believe to be a high bias. No we're looking for data to see what the saturation actually is and that's about it.

I'll add (unintelligible) yes and we certainly don't think that anyone economically and or maybe that actually that might not be completely true but the cost of (unintelligible) or laser water vapor devices is very high especially for lease level measurement and that's why we're trying to achieve an across the board solution for how to do it with water vapor saturation.

(Liz): Thank you (Ron). I think we're going to end. Hello okay one more. One more question. Very quick okay.

(Leslie Garvis): Hi my name is (Leslie Garvis) I'm with (Bonnett and Well). And I just want to make you aware of a situation that those of us in New Mexico could run into if it's not cost effective to comply with some of this and we have to start shutting some of our wells in because of that. The State of New Mexico only allows us to have so many wells down for a given period of time. For example we're only allowed to have five down for 15 months.

So what ends up happing during that time if we're not able to comply and we have to shut these in we're going to run into having to plug a lot of wells and that's going to mean a lot of lost revenue for BLM as well as us as an operator. So I just want you to be aware of situations like that and you may already know about it. But the State puts limitations on us even on BLM land.

(Liz): Thank you. Thank you all for being here today. I'd like to thank the panel here for their expertise. Thank you so much. To our lovely court reporter who was fantastic. And to the folks from DC who I think would like to say a little something. Thank you all so much I appreciate it.

Woman 2: Well thank you. Thank you (Liz) and I thank you all for your expertise that you're adding to our experts. So just thank you again please send your comments in we look forward to seeing them and thanks for coming. Have a good afternoon.

(Liz): And Operator (unintelligible).

Coordinator: Thank you and this does conclude today's conference you may disconnect at this time...

Man 5: (Unintelligible) please (reply).

END